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TITLE: INDUCED FRACTURES: WELL STIMULATION THROUGH FRACTURING

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INDUCED FRACTURES--WELL STIMULATION THROUGH FRACTURING

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ABSTRACT

Republic Geothermal, Inc., and its subcontractors have planned and executed seven fracture stimulation treatments under the Department of Energy-funded Geothermal Well Stimulation Program. The objective of this program is to demonstrate that geothermal well stimulation offers a technical alternative to additional well drilling and redrilling for productivity enhancement which can substantially reduce development costs. Well stimulation treatments have been performed at Raft River, Idaho; East Mesa, California; The Geysers, California; and the Baca Project Area in New Mexico. Six of the seven stimulation experiments were technically successful in stimulating the wells. The two fracture treatments in East Mesa more than doubled the production rate of the previously marginal producer. The two fracture treatments at Raft River and the two at Baca were all successful in obtaining significant production from previously nonproductive intervals. The acid etching treatment in the well at the Geysers did not have any material effect on production rate.

INTRODUCTION

The stimulation of geothermal production wells presents some new and challenging problems. Formation temperatures in the 275-550°F range can be expected and the behavior of fracturing fluids and fracture proppants at these temperatures in a hostile brine environment must be carefully evaluated in laboratory tests. To avoid possible damage to the producing horizon of the formation, the high-temperature chemical compatibility between the *in situ* materials and the fracturing fluids, fluid loss additives, and proppants must be verified. In geothermal wells, the necessary stimulation techniques are required to be capable of initiating and maintaining the flow of very large amounts of fluid. This necessity for high flow rates represents a significant departure from conventional oil field stimulation and requires the creation of propped fractures with high flow conductivity (for fluid transport to the wellbore) and large fracture surface areas (for fluid drainage in the case of matrix permeability dominated formations).

The objective of well stimulation is to initiate and maintain additional fluid production from existing wells at a lower cost than either drilling new replacement wells or multiply redrilling existing wells. The economics of well stimulation will be vastly enhanced when proven stimulation techniques can be implemented as part of the well completion (while the drilling rig is still over the hole) on all new wells exhibiting some form of flow impairment. Technically successful induced fractures have been created in formations that produce hot water as a result of matrix permeability and in formations that produce hot water from naturally existing fracture systems.

PROPPANTS

Proppants are an important aspect of hydraulic fracturing because they help retain the fracture conductivity created by the injected high-pressure fracturing fluids. In order to achieve effective stimulation, the fracture conductivity (permeability times fracture width) after the well is returned to production must be larger than the reservoir permeability. To obtain this high conductivity, a large granular proppant is injected along with the fracturing fluid and deposited in the fracture. This material must be strong enough to maintain a high permeability when subjected to the formation closure stresses. For geothermal wells, the proppant must also be inert to minimize degradation in the presence of high-temperature brines.

Although sand is generally used as a proppant, it is not strong enough to withstand the conditions in geothermal wells at elevated temperatures. Sand is definitely affected by temperature, particularly when tested in hot water or brine at various closure stresses. Figure 1 shows the effect of temperature and closure stress on common Brady frac sand (20/40 mesh). Crushing starts below 4,000 psi at room temperature and begins between 2,000 and 3,000 psi at elevated temperatures. At 10,000 psi closure stress, only a fine powder is left and this can damage a high closure stress well rather than stimulate it. Although the properties of Ottawa frac sand are superior to those of Brady frac sand, elevated temperature tests at 350°F

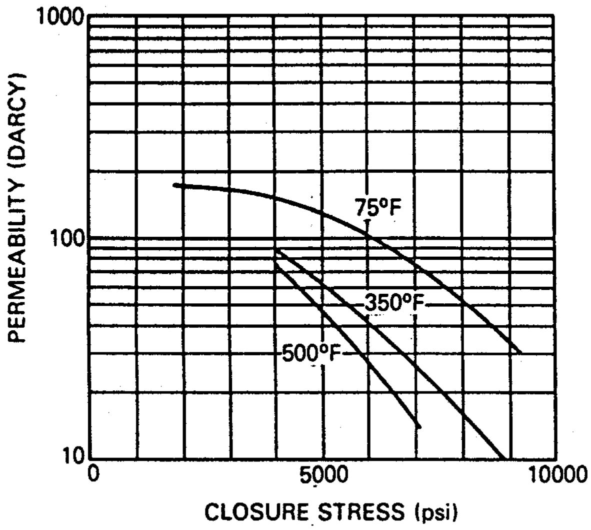

Figure 1. Temperature and closure stress effects on 20/40-mesh Brady frac sand.

show crushing starting below 4,500 psi and below 3,000 psi at 500°F. These are short term results and only suggest the severity of long term field results.

There are several mechanisms that can destroy sand grains in the fracture. First, the sand is brittle and point-to-point loading can cause brittle failure. Second, sand is full of microfractures and faults which weaken the sand. Finally, when sand is stressed in a corrosive medium like hot water, stress corrosion cracking appears to destroy the sand at low closure stresses. High temperatures and high stresses combine to bring out the worst properties of sand.

To more fully explore the high-temperature effects on proppants, Maurer Engineering set up a modified linear flow cell able to withstand internal pressures up to 1,000 psi at 500°F. By using water preheating and a heated Dake Hydraulic Press to impose the closure stress, actual geothermal reservoir conditions can be simulated. A brief summary of significant proppant properties based on both previously published and new Maurer Engineering data [1,2,3] is presented in Table 1.

The strongest and highest permeability proppant tested to date is Resin Coated Bauxite. The core of this proppant is composed of many small particles of bauxite sintered together at high temperature to allow some deformation before crushing. The core is covered with an uncured resin that polymerizes at elevated temperatures to form a cohesive high strength outer layer. This cohesive layer bonds the proppant pack together and minimizes sand and proppant flowback during subsequent well production. This proppant exhibits almost no temperature sensitivity or permeability decrease under load. Sintered Bauxite proppant, supplied by the Carborundum

PROPPANT TYPE	PERMEABILITY RETENTION UNDER 5,000 psi LOAD (%)	SOLUBILITY IN HIGH TEMPERATURE GEOTHERMAL WATER	SPECIFIC GRAVITY
RESIN COATED BAUXITE	100%	Slightly soluble above 500°F, insoluble below 500°F	3.37
RESIN COATED SAND	100%	Slightly soluble above 500°F, insoluble below 500°F	2.53
SINTERED BAUXITE	90%	Insoluble	3.60
OTTAWA SAND	68%	Slightly soluble, temperature + pH sensitive	2.65
BRADY SAND	34%	Slightly soluble, temperature + pH sensitive	2.65
GLASS BEADS	23%	Slightly soluble, temperature + pH sensitive	2.41
COLORADO SAND	15%	Slightly soluble, temperature + pH sensitive	2.65

Table 1. Proppant properties (data based on short-term 350°F tests with 20/40-mesh materials).

Company, yielded a permeability only slightly lower than that of the Resin Coated Bauxite. Temperature sensitivity was also very low and only a slight decrease in permeability is noted at the highest closure stresses resulting from particle repacking and slight crushing. These experimental results are presented in Figure 2 as a function of closure stress at 350°F along with the data for Resin Coated Sand proppants. Resin Coated Sand uses a conventional frac sand core covered with an uncured resin analagous to the Resin Coated Bauxite. The Resin Coated Sand has low temperature sensitivity, a permeability approximately 40% lower than that of the Carborundum Company-supplied Sintered Bauxite, and relatively little permeability change over the range of closure stresses. Resin Coated Sand has the advantage of a much lower cost per pound compared with the bauxite proppants, and its lower density can lead to better proppant placement in large high-temperature fractures. The superior permeability of all these man-made proppants at high temperatures and high closure stresses makes them the logical choice over conventional frac sands for geothermal well service.

The preceding paragraphs have addressed proppant performance as a function of temperature

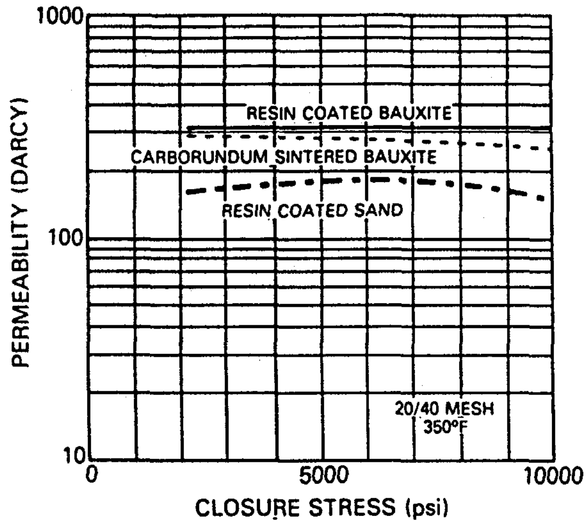

Figure 2. Permeability vs. closure stress for temperature-insensitive proppants.

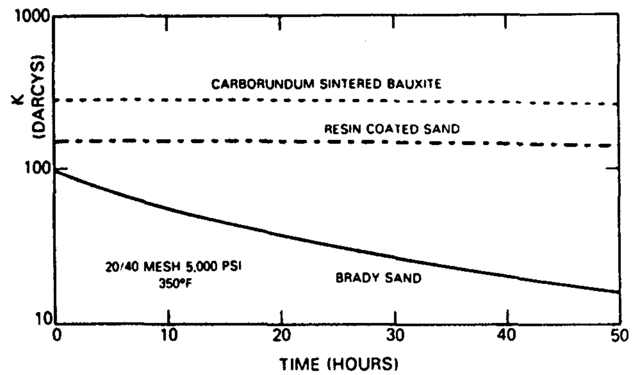

Figure 3. Permeability retention with time at 350°F and 5,000 psi closure stress (20/40-mesh proppants).

and closure stress based on short-term (less than 4 hr) laboratory tests. Permeability retention as a function of time must also be considered in evaluating a proppant's ultimate downhole performance. Using the Maurer Engineering modified linear flow cell, 50-hr tests were performed at a temperature of 350°F with a constant closure stress of 5,000 psi. Sintered Bauxite, Resin Coated Sand, Ottawa frac sand, and Brady frac sand of 20/40 mesh were tested under these conditions. Upon completion of the 50-hr tests, an examination of the proppants showed no change in the Sintered Bauxite or Resin Coated Sand, but both frac sands contained over 30% fines and were obviously not suitable as proppants under these conditions. These results are summarized in Figure 3 where dynamic permeability loss with time indicates crushing, chemical degradation, or movement of fines within the proppant pack.

FRACTURING FLUIDS

Of prime importance in the success of a hydraulic fracturing operation is the ability of the fracturing fluid to perform its designed function under actual reservoir conditions. Long chain, water soluble polymers have been used for many years in the hydraulic fracturing of oil wells and recently their use has been extended to high-temperature geothermal wells. Little is known about the high-temperature degradation of many of these polymers other than an extreme viscosity drop as the temperature exceeds 250-300°F. The function of the polymer is to viscosify the fracturing fluid to help transport the proppants into the induced fractures and to slow the invasion of the fluid into the formation. In addition, a successful polymer must not cause any permeability reduction of the reservoir formation or propped fracture due to plugging by itself or its high-temperature degradation products.

In support of the geothermal well stimulation program, numerous laboratory tests on prospective fracturing fluids have been conducted by Maurer Engineering [4] and Vetter Research [5]. The main parameter measured throughout these tests is the apparent viscosity of the frac fluid at geothermal reservoir conditions. Other important parameters which are measured on some of the better fluid systems are fluid loss control, proppant suspension or carrying capacity, and the carbohydrate or total organic carbon content of the polymer-fluid system as a measure of its degradation with time and temperature. Although all polymer systems show a sharp decline in viscosity with increasing temperature, there are many techniques that can be used to delay this decline or degradation in properties. One such technique is the addition of a small amount of methanol to the polymer water solutions, which has a stabilizing effect on the fluid. Other proprietary products which can be added as high-temperature stabilizers are also available. Dissolved oxygen can cause polymer degradation but, by adding an oxygen scavenger to the water, this effect can be minimized. The effect of temperature on the viscosity of some proposed polymer-water frac fluid systems is illustrated in Figure 4. The rapid decline in viscosity of polymer "A" at temperatures above 200°F could result in poor proppant placement in a high-temperature geothermal stimulation treatment. With improved fluid systems as depicted by polymer "C", the effective working temperature can be increased by 150°F. When these improved fluid systems are combined with large water prepads for formation cooling and very high fluid injection rates, high-temperature geothermal wells can be successfully fractured and propped.

The type and amount of polymer determines the speed and extent of degradation. Polymers used in fracturing are of three basic types, i.e., polysaccharides, modified celluloses, and polyacrylamides. These particular polymers are chosen because of their unique ability to viscosify water and, at the same time, to reduce

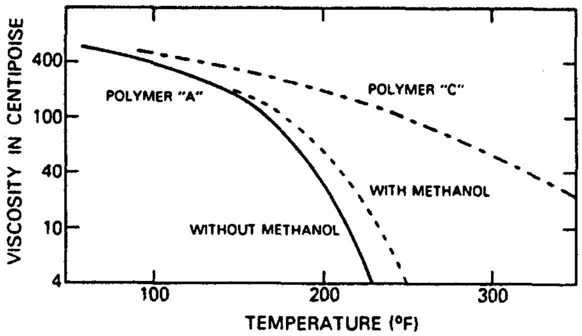

Figure 4. Polymer-water frac fluid viscosity vs. temperature.

tubular friction and have a good tolerance to brine. An ideal frac fluid would retain its desirable properties at high temperature until it has done its job of placing the proppant in the fracture. Cleavage of the long polymer chains would then occur to allow easy removal of the fracturing fluid upon well production with minimal degradation products left behind in the formation. Laboratory tests to define the degradation of water-soluble polymers have been useful not only for a fundamental understanding of frac fluid behavior, but also in helping to select or reject fluids for specific reservoir applications. Monitoring the produced fluid returns after each stimulation treatment for amount and level of degradation products has been an important aspect of each field test.

SITE SELECTION

In selecting candidate reservoirs and wells, the Geothermal Well Stimulation Program was influenced by many contributing factors. In addition to the obvious technical considerations, the program evaluated cost-sharing arrangements provided by the well owner to conserve program funds and the potential impact that effective stimulation could have on the future commercial development of the field. This latter consideration played a strong role in the selection of the Raft River and Baca Project areas for performing four well stimulation treatments. Raft River was selected at the request of DOE Headquarters to support brine production activities required for the upcoming 5 MW geothermal power plant. Although Baca was of tremendous technical importance to the program because of its very high reservoir temperature, the fact that it was part of a DOE/Union/PNM Demonstration Plant Project considerably enhanced its priority status. The importance of The Geysers as the world's largest commercial electric generating geothermal field, along with the cost-sharing benefits offered by Union, was also instrumental in its selection for a well stimulation treatment. While each of these sites proved to be an excellent choice from a technical stand-point, it did result in five of the seven field stimulation treatments being performed in fracture dominated reservoirs. Only the two treatments at East Mesa addressed the very significant problems associated with low permeability regions in matrix-type producing formations, including well skin damage resulting from drilling and completion operations.

RAFT RIVER FIELD (Treatments 1 and 2)

Raft River, Idaho, is a low-temperature (260-290°F) hydrothermal resource. Wells RRGE-1 and RRGE-2 are the best producing wells in the field and appear to intersect a natural fracture zone in the quartz monzonite reservoir. These fractures have high transmissibility, with a permeability thickness (kh) of greater than 50,000 md-ft. Wells RRGE-3, RRGP-4, and RRGP-5 are less productive and were all considered for stimulation. Wells RRGP-4 and RRGP-5 were chosen as the best two candidates for stimulation because RRGE-3 is farther from the best producing wells and its mechanical configuration is very complex [6,7].

Before stimulation, RRGP-4 was essentially nonproductive. RRGP-5, however, was capable of flowing at a stabilized rate of 66,000 lb/hr and produced more than 283,000 lb/hr with a pump. This is adequate productivity, but the production came from the upper portion of the completion interval, and the produced fluid temperature of 255°F was undesirably low. Based on the performance of the better wells in the field and the proximity of Wells RRGP-4 and RRGP-5 to the Bridge and Narrows Faults, it was considered likely that highly productive fractures existed near the wells. Hydraulic fracture treatments in the deeper intervals were chosen as the best means to connect the wells with major productive fractures and to achieve the desired produced fluid temperatures of 270°F or greater.

To isolate the deep interval of Well RRGP-4 for the fracture treatment, a 7-in. liner was cemented through the upper portion of the openhole interval. This isolated a 195-ft openhole interval (4,705-4,900 ft) near the bottom of the well for the hydraulic fracture treatment. The technique employed was a four-stage dendritic fracture treatment. It was chosen because, if dendritic fracturing was achieved, it offered the best chance of intersecting major natural fractures. The main concern was that a single, planar fracture might only parallel and not intersect the principal natural fractures. The dendritic, or reverse flow, fracturing technique is designed to create branching or diversion of the fracture wings by downhole stress modification. Multiple stages or pumping periods are used with each stage utilizing a low-viscosity fluid, sand slugs, and two brief flow-back periods. High pumping rates are used in these treatments to offset fluid leakoff into natural fractures and to enhance erosion in the fracture faces by the proppant and fine sand.

The 7,900-barrel (bbl) treatment was pumped at a rate of 50 barrels/minute (BPM) and utilized a low-viscosity polymer gel frac fluid (HP guar) carrying relatively low concentrations of proppant. The treatment included 50,400 lb of 100-mesh sand added for leakoff control and 58,000 lb of 20/40-mesh sand proppant. Use of both sand and HP guar was considered acceptable here because of the relatively low temperature.

Following the treatment, the U.S. Geological Survey (USGS) ran their high-temperature acoustic borehole televiewer and observed that the created fracture extended the full 195-ft height of the open interval and was oriented approximately east-west, parallel to the nearby Narrows Fault. A section of the fracture is shown in Figure 5. In the post-stimulation flow test, the well produced at a stabilized rate of 28,300 lb/hr with a downhole fluid temperature of 270°F. This rate represented at least a five-fold increase over the pre-stimulation rate; but even with an estimated pumped rate capability of more than 100,000 lb/hr, the well was still subcommercial. The produced fluid temperature is significantly higher than past measurements. This fact suggests that the new artificial fracture is producing fluid from a deep zone not open in the original hole. The chemical data further support this interpretation in that the extent of polymer degradation determined chemically is consistent with fluid exposed to higher temperatures.

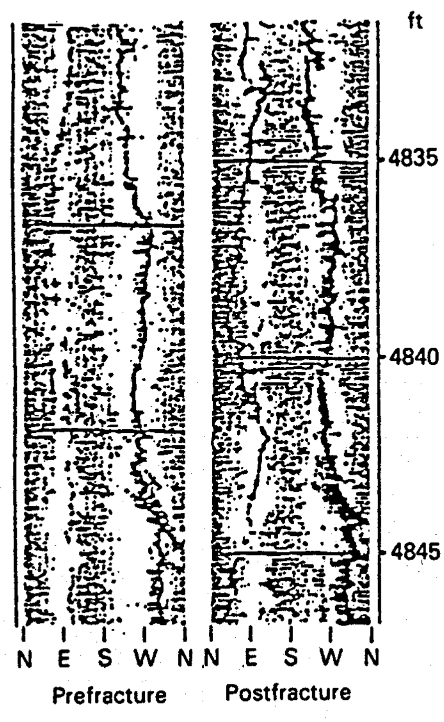

Figure 5. Pre-existing and propped fractures in Raft River RRGP-4.

Conventional fracture-type curve analysis (log-log plot) yields a fracture length of approximately 335 ft and a permeability thickness of 800 md-ft. The Horner plot of the same pressure buildup data has two straight line segments after the fracture dominated period, one during early time (less than 15 hr) and one during later time (greater than 15 hr). These two segments give kh values of 1,070 md-ft and 85,000 md-ft, and suggest the presence of more than one permeability zone in the vicinity of the wellbore. Also, a negative skin factor (-6.0) indicates a stimulated zone close to the wellbore.

Well RRGP-5 originally had good productivity from the upper portion of the completion interval. The goal of the treatment for this well was a similar or higher productivity, but from a deeper, hotter interval. The well was recompleted similar to RRGP-4, as shown in Figure 6, in preparation for this stimulation treatment. The recompletion consisted of cementing a 7-in. liner through the upper portion of the openhole interval which sealed off the existing producing interval and left a 216-ft openhole interval near the bottom of the well. A large fracture treatment designed to create a single planar propped fracture was selected for RRGP-5. The treatment consisted of 7,600 bbl of a relatively low-viscosity polymer gel (HP guar) with 84,000 lb of 100-mesh sand for leakoff control and 347,000 lb of 20/40-mesh sand proppant. Near the end of the treatment, the pumping rate was gradually reduced

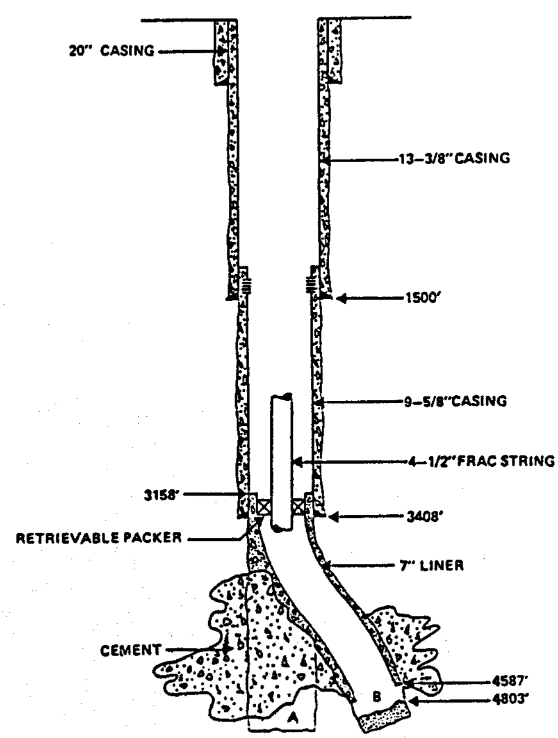

Figure 6. Well schematic of Raft River RRGP-5.

in an effort to sand the well out and leave the fracture propped near the wellbore with an open, high-conductivity channel near the top.

Following the treatment, the USGS borehole televiewer showed that the created fracture spanned the upper 135 ft of the open interval. The fracture was oriented northeast-southwest, parallel to the nearby Bridge Fault. In the post-stimulation production test, the well stabilized very rapidly at a 94,300 lb/hr rate with a 30 psia wellhead pressure. The produced fluid temperature was unchanged from the pre-stimulation flow condition. Following the natural flow test, a pump was installed in the well and it produced more than 307,000 lb/hr. Chemical analysis of the produced fluid indicated a relatively low rate of polymer degradation in the reservoir, confirming that the frac fluid traveled upward into a cooler portion of the reservoir.

Pressure buildup and temperature data also strongly suggest that the fracture treatment went upward to the original producing interval (possibly through the original wellbore). The Horner plot of the pressure buildup data shows only a short transition phase between the fracture dominated period and the late time constant pressure period. Estimates of the late time formation kh were large--greater than 100,000 md-ft. The Horner analysis indicates a very large positive skin factor. This skin factor is probably not due to formation damage but rather to the limited entry nature of the completion.

EAST MESA FIELD (Treatments 3 and 4)

The East Mesa field, in the Imperial Valley of California, is a moderate-temperature reservoir producing from a sandstone and siltstone matrix. Several features of East Mesa made it an excellent choice for the second set of field experiments. The reservoir is known in more detail than most other geothermal reservoirs and this in-depth knowledge provides a sound basis for designing and evaluating stimulation treatments. The moderate temperature range (320-350°F) was the next logical step from Raft River conditions in the evaluation of fracture fluids, proppants, and mechanical equipment. The selection of a matrix-type reservoir was also important at this stage of the program. Furthermore, the reservoir fluids, with a total dissolved solids content of less than 2,000 mg/l, were not expected to chemically interfere with the stimulation fluids or tracers [6,8].

Well 58-30, selected for these experiments, is ideally suited mechanically. Unlike many other geothermal wells at East Mesa and elsewhere, it is completed with a cemented, jet perforated liner (Figure 7). This afforded an opportunity to easily isolate zones of a size that can be effectively treated and evaluated. The first treatment was a planar-type hydraulic fracture of a 247-ft, low-permeability sandstone interval (6,587-6,834 ft) near the bottom of the well. This zone has good sand development, but the permeability has been severely reduced because of authigenic cementation by carbonate minerals. Porosity is still high enough, however, to provide good storage capacity. A fracture treatment of this zone was intended to create a high conductivity linear flow channel in the low permeability area surrounding the well, thereby enhancing the flow capacity. The treatment consisted of 2,800 bbl of a viscous crosslinked polymer frac fluid (HP guar), 44,500 lb of 100-mesh sand as a fluid loss additive, 59,000 lb of 20/40-mesh sand proppant, and 60,000 lb of 20/40-mesh Resin Coated Sand proppant. The fluid was pumped at an average rate of 40 BPM during the treatment.

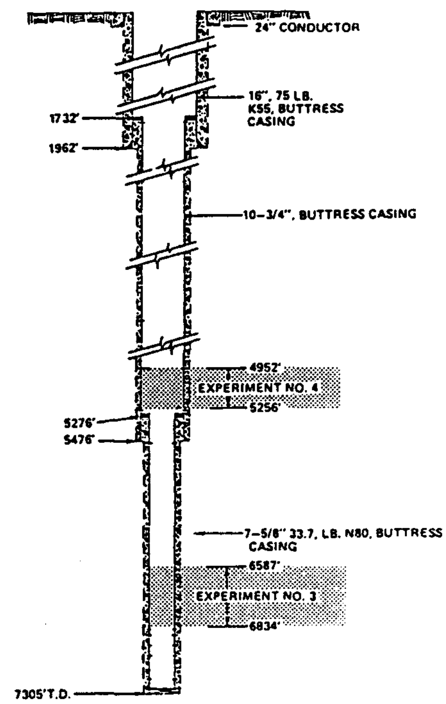

Figure 7. East Mesa Well 58-30 completion details.

The second treatment was a dendritic-type fracture treatment in a shallower, higher permeability, 304-ft interval (4,952-5,256 ft) of the same well. This cooler upper zone, drilled with a predominantly bentonitic mud system, has good sands (high porosity and permeability) which show permeability impairment near the wellbore. The staged treatment was designed to create multiple short fractures through the damaged zone around the wellbore. The treatment consisted of 10,300 bbl of low viscosity frac fluid (HP guar) and 44,000 lb of 100-mesh sand pumped in five stages at an average rate of 48 BPM. The 100-mesh sand was injected in slugs as a fluid-loss control agent in the 50-md permeability sandstone, as a diverter for succeeding stages of the treatment, and to erode flow channels in the fracture faces.

The well was first production tested to evaluate the fracture experiment on the upper zone. The lower section of the well, from 6,547 ft to TD, was sanded back to prevent flow from the lower frac zone. The well flowed an average of 132,000 lb/hr. Reservoir pressure buildup data show the total open interval permeability thickness was 9,427 md-ft, or approximately a 108% increase in kh for the upper frac zone. This analysis indicates the shallow hydraulic stimulation treatment of the high permeability, upper interval was very successful. The upper zone treatment to correct near-wellbore damage is of particular importance because such mud and cement damage is believed to be a common cause of impairment in Imperial Valley geothermal wells.

Well clean-out operations were initiated to remove the sand covering the lower frac zone. The coil tubing being used to lift sand out of the well parted and left approximately 5,170 ft of tubing in the hole. Following the fishing and cleanout operations, the entire wellbore was opened for a flow test and the well achieved a total flow rate of about 198,000 lb/hr. The lower zone, stimulated with a small hydraulic fracture treatment, showed a 19% increase in kh but an 84% increase in fluid production. In addition, the overall fluid production temperature increased by 5°F. Higher temperatures reduce the hydraulic head in the wellbore (lower the flash point) and thereby increase the natural flow rate more than would be expected from the kh increase alone. The pre- and post-stimulation test data for well 58-30 are summarized in Table 2.

In summary, Well 58-30 was successfully stimulated by the two fracture treatments. Although some of the improvement in the upper interval was lost during workover operations, the overall productivity of the well had been increased 114% and the kh had been increased 38%.

	PRE-STIMULATION	UPPER ZONE FRAC EVALUATION*	POST-STIMULATION
UPPER INTERVAL-EXPERIMENT NO. 4 (4,952-5,266 ft)			
% INFLOW	38	74	47
kh (md-ft)	2,848	6,955	4,846
INTERMEDIATE INTERVAL- (5,266-6,587 ft)			
% INFLOW	33	26	28
kh (md-ft)	2,472	2,472	2,887
LOWER INTERVAL-EXPERIMENT NO. 3 (6,587-6,834 ft)			
% INFLOW	29	--	25
kh (md-ft)	2,173	--	2,578
TOTAL COMPLETION (4,952-6,834 ft)			
kh (md-ft)	7,493	9,427	10,311
Q (B/D)	6,992	9,922	14,921
T @ 4,900 ft (°F)	326	--	331

*ONLY INTERVAL 4,952 FT TO 6,520 FT OPEN TO FLOW

Table 2. Summary of production test data for East Mesa Well 58-30.

THE GEYSERS FIELD (Treatment 5)

The fifth experiment was performed at The Geysers geothermal area in Sonoma County, California, and was cost-shared with the well operator, Union Geothermal Company. The well chosen for this chemical stimulation treatment was Ottoboni State No. 22. This well is completed openhole from 4,600 to 8,360 ft in naturally fractured graywacke. The reservoir temperature is about 460°F. The well was plugged back to 5,600 ft to isolate the upper 1,000 ft of openhole interval for the treatment [6].

The stimulation technique employed was an acid etching treatment (Halliburton Services MY-T-ACID). A 476-bbl low viscosity prepad was pumped to provide cooling of the tubulars and formation. Following the prepad were 476 bbl of high viscosity crosslinked gel fluid (HP guar) and 476 bbl of 10% HF-5% HCl acid solution with corrosion inhibitors and friction reducer. After the acid, an additional 445 bbl of low viscosity fluid were injected as displacement and overflush. This treatment concept is illustrated in Figure 8.

Fracture fluid pump rates of 20-40 BPM and a surface pressure of 3,000 psig were estimated for this stimulation treatment. However, no significant surface pressure was recorded and all fluids easily flowed into the interval. Subsequent evaluation of well performance showed that no noticeable stimulation had been achieved. Temperature and radioactive tracer surveys, shown in Figure 9, indicated that the fracture fluids entered natural, pre-existing fracture channels in the lower 650 ft of the 1,000-ft openhole interval. In addition, chemical tracers injected sequentially with the frac fluids returned in a highly mixed fashion. The small fluid volume employed and widespread entry interval probably resulted in shallow penetration of the formation.

After the treatment, the well was cleaned out to total depth and returned to its pre-stimulation condition. The final steam flow rate was 41,200 lb/hr, which is similar to the rate recorded before the stimulation. This confirmed the fact that the acid etching treatment did not create any new, high-conductivity flow paths to the main reservoir system. There is no evidence to suggest, however, that the acid etching technique will not work, and the technique needs to be attempted again in a shorter treatment interval or with larger fluid volumes.

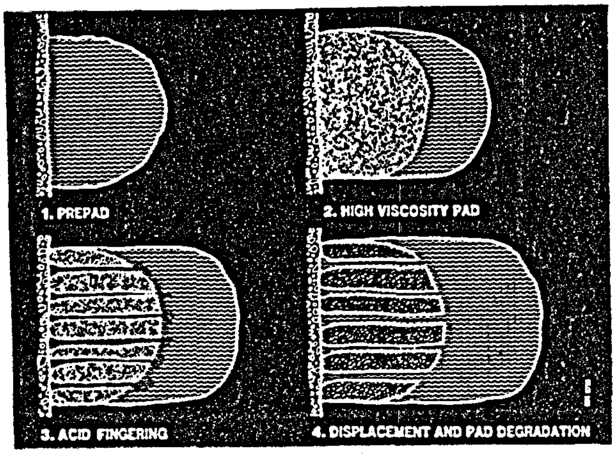

Figure 8. Acid etch treatment concept used at The Geysers, Well OS-22.

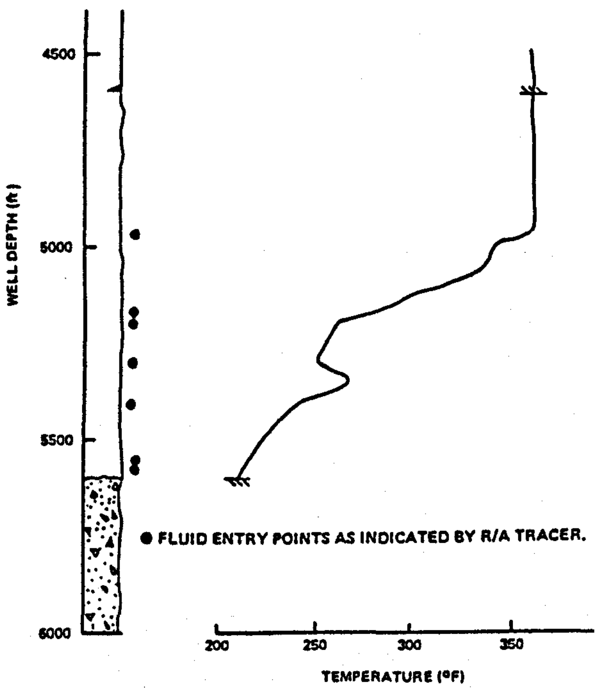

Figure 9. Temperature and gamma ray survey in Well OS-22 after stimulation treatment.

BACA FIELD (Treatments 6 and 7)

The Baca reservoir lies within the Jemez Crater, Valles Caldera, and is defined by more than 20 wells completed to date in the Redondo Creek area by Union Geothermal Company of New Mexico. The main reservoir, 4,000 to 6,000 ft in thickness, is composed of volcanic tuffs with low permeability and a primary flow system of open fracture channels. In the Redondo Creek area, wells have encountered a high temperature (550°F) liquid-dominated reservoir, but numerous wells have not been of commercial capacity, primarily because of the absence of productive natural fractures at the wellbore [6].

After considering several candidate wells, Baca 23 and subsequently Baca 20 were selected for the fracture treatments. These wells were selected because: (1) they were poor producers; (2) the fracture system is present in the area as proven by the surrounding wells; (3) the wells could be recompleted to isolate the stimulation interval; (4) observation wells were available within 1,500 ft; (5) the wellsites were large enough for the frac equipment; and (6) in the case of Baca 23, the rig was already on location.

Baca 23 was flow tested and would not sustain flow. An interval from 3,300 to 3,500 ft was selected for fracture stimulation. Productive fractures had previously been encountered near this depth approximately 200 ft away in Baca 10. The temperature in the zone selected was approximately 450°F. Because the top of the selected interval was deeper than the existing 9-5/8-in. liner, a 7-in. liner was cemented to a depth of 3,300 ft to exclude the interval above. The lower portion of the hole was sanded back and plugged with cement to 3,531 ft to contain the treatment in the desired interval. The treatment interval was totally nonproductive after being isolated for the stimulation treatment.

A large hydraulic fracture treatment was performed on the well consisting of 7,641 bbl of fluid and 180,000 lb of 20/40-mesh proppant pumped in eight stages. A 3,600-bbl cold water prepad was pumped at an average rate of 38 BPM. The frac fluid consisted of 4,000 bbl of cross-linked polymer gel (HP guar) pumped at an average rate of 66 BPM and an average surface pressure of 3,300 psig. Although basically a conventional hydraulic fracture treatment, the high formation temperature (450°F) dictated special design and materials selection requirements. The large water prepad was dedicated to wellbore and fracture pre-cooling with the frac fluid used to place the proppant. While frac fluid properties are known to degrade rapidly at high temperature, these effects were minimized by pre-cooling, by pumping at high rates, and by limiting the frac interval to 231 ft. Proppants were selected for their insensitivity to the high temperature and both Resin Coated Sand and Sintered Bauxite were used.

Twelve hours after the frac job, a temperature survey was obtained by Denver Research Institute. This survey showed a zone cooled by the frac fluids estimated to be more than 300 ft in height at the wellbore. A 6-hr production test through drillpipe was performed in which transient downhole pressure and temperature measurements were obtained. A unique testing method was utilized to overcome the data gathering problems usually associated with flow testing a geothermal well. The procedure was a combination of conventional drillstem test (DST) methods to eliminate large wellbore storage effects and gas lift to maintain steady, single-phase flow to the wellbore. The gas lift was provided by injecting nitrogen gas at depth through coil tubing inside the drillpipe. As a result of this procedure, the well flowed at a low, steady rate (about 21,000 lb/hr) and the transient pressure data obtained downhole provided an indication of wellbore storage effects, fracture flow effects, and reservoir transmissivity.

A conventional Horner analysis of the pressure buildup data yielded an average reservoir permeability thickness of 2,500 md-ft. This compares closely with results from other noncommercial wells in the area. Although the linear flow indicators were weak, the length of the fracture was calculated to be about 300 ft using the pressure vs. square root of time analysis. A skin factor of -3.9 was also calculated. The maximum recorded temperature was 342°F, which indicated that the near wellbore area had not recovered from the injection of cold fluids.

Following the modified DST, a 49-hr flow test was performed to determine the well's productive capacity. The results showed that the well could produce approximately 120,000 lb/hr total mass flow at a wellhead pressure of 45 psig, although the rate was continuing to decline. Union then performed a long-term flow test on the well. A temperature profile of the well prior to this test showed that the bottomhole temperature still remained low (401°F). Temperature and pressure surveys recorded a maximum temperature of 344°F and a maximum pressure of 120 psig at 3,500 ft. Therefore, two-phase flow was occurring in the formation, with the steam fraction estimated at more than 50%. This two-phase flow condition has been observed in other wells in the field.

Of greater concern is the low productivity observed during this last test. The mass flow rate had dropped to 73,000 lb/hr (about 50% steam) with a wellhead pressure of 37 psig. Since the well recovers productivity following each shut-in period and then exhibits the same decline again, the cause of the rate decline is probably not due to scaling in the formation. Partial closing of the fracture is possible because of the pressure drawdown. The most probable explanation, however, is that the productivity loss is the result of relative permeability reduction associated with two-phase flow effects in the formation. The relatively low formation temperature in the completion interval also contributes to the well's poor productivity.

Baca 20 was originally completed as shown in Figure 10A with a cemented 9-5/8-in. liner and a 7-in. slotted liner hung at 2,390 ft. The 7-in. slotted liner was pulled, lost circulation zones cured using cement plugs, and then a 7-in. blank liner was cemented in place at 4,880 ft in order to isolate the desired treatment interval (Figure 10B and 10C). This particular 240-ft interval was chosen primarily because the best production in the area has been found near the bottom of the Bandelier Tuff and because of its high reservoir temperature (540°F).

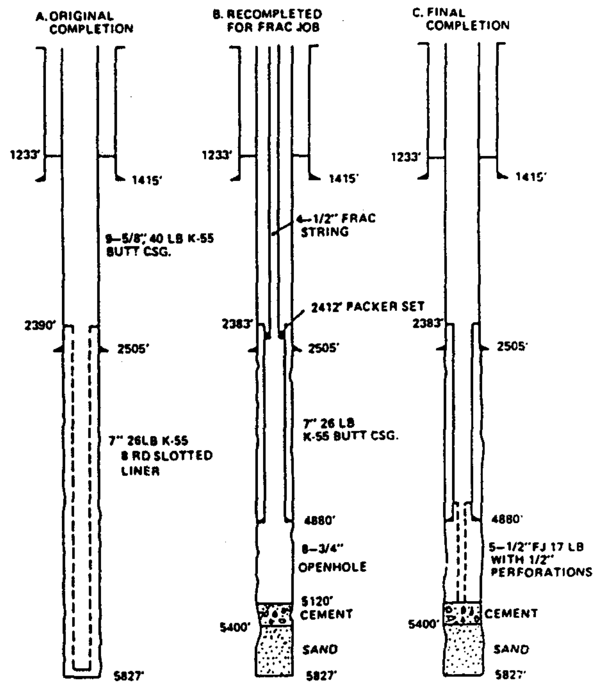

Figure 10. Baca 20 completion details.

The hydraulic fracture treatment was accomplished using a total fluid volume of 8,700 bbl. The high formation temperature (540°F) once again dictated special treatment design and materials selection. A 3,000-bbl fresh water prepad was used to cool the wellbore and fracture. The proppant selected (Sintered Bauxite) was carried by a 60-lb/1,000 gal hydroxypropyl guar polymer gel mixed in 5,700 bbl of fresh water. This fluid was a new high-pH crosslinked HP guar system having better stability at high temperature. The gel was crosslinked as it was being pumped. In an effort to stop leakage into the small natural fractures, approximately 4,200 lb of 200-mesh calcium carbonate and 42,000 lb of 100-mesh calcium carbonate were pumped as fluid-loss additives. The 100-mesh material was injected in "slugs" to enhance its chances of bridging on the fractures. This material was used in lieu of sand as in the Baca 23 job. The desired goal of ending the treatment at a relatively high proppant concentration was achieved. A comparison of the Baca 23 and Baca 20 stimulation treatments is presented in Table 3.

The 240-ft stimulation interval was nonproductive prior to the treatment, although there was a small rate of fluid loss during the well completion operations. This indicated that at least one lost circulation zone existed in the wellbore. Approximately 12 hours after the frac job, the first of several temperature surveys was obtained in the well. These temperature surveys showed a zone cooled by the frac fluids, estimated to be less than 100 ft in height, near the bottom of the open interval. In addition, the

	BACA 23	BACA 20
INTERVAL	231 ft	240 ft
DEPTH	3300-3531 ft	4880-5120 ft
WATER PRE-PAD	3600 bbl	3000 bbl
GELLED WATER FRAC FLUID	4000 bbl	5700 bbl
PROPPANTS	90,000 lb of 20/40-mesh Sintered Bauxite, 90,000 lb of 20/40-mesh Resin Coated Sand	120,000 lb of 16/20-mesh Sintered Bauxite, 120,000 lb of 12/20-mesh Sintered Bauxite
PUMPING RATE	40-75 BPM	40-80 BPM

Table 3. Comparison of Baca 23 and Baca 20 stimulation treatments.

zone located behind the 7-in. liner casing at approximately 4,720 ft also indicated some cooling. This zone was apparently cooled by the workover fluids and possibly by the fracturing fluids; however, the communication between this zone and the open interval (if it exists) appears to be at some distance away from the wellbore.

A 6-hr production test through drillpipe was performed in the same manner as the drillstem test at Baca 23. A steady rate of about 21,000 lb/hr single-phase flow was maintained to the wellbore. Transient pressure and temperature data were obtained downhole during the DST. A conventional Horner analysis of the pressure buildup data yielded an average reservoir permeability thickness of 1,000 md-ft. Evaluation of these data also indicated small wellbore storage effects and fracture (linear) flow near the wellbore. Although the indicators of linear flow were weak, the length of the fracture was calculated to be about 160 ft from the pressure data. A skin factor of -4.8 was also calculated. Numerical simulation of a high conductivity fracture in a low permeability formation supports this interpretation, although the solution is not unique. The maximum recorded temperature during the test was 320°F and indicated that the near wellbore area had not recovered from the injection of cold fluids. Following the modified DST, a 14-day flow test was performed to determine the well's productive capacity. The well produced approximately 120,000 lb/hr total mass flow initially, but declined rapidly to a final stabilized rate of approximately 50,000 lb/hr (wellhead pressure of 25 psig) under the two-phase flow conditions in the formation.

To summarize, large hydraulic fracture treatments were successfully performed on both Baca 23 and Baca 20. Production tests indicated that high conductivity fractures were propped near the wellbore and communication with the reservoir system was established. The productivities of Baca 23 and Baca 20 have declined to noncommercial levels since the fracture treatments. The probable cause is relative permeability reduction associated with two-phase flow effects in the formation. The ability of Baca 23 to produce substantial quantities of fluid at a high wellhead pressure is limited because of the low formation temperature in the shallow treatment interval. The productivity of Baca 20 is severely restricted because of the low permeability formation surrounding the artificially created fracture.

Because of the high temperatures encountered in the Baca formation, special OTIS casing packers dressed with Y267 EPDM elastomeric seals were required. This elastomer, developed by L'Garde, Inc. [9], has continuously demonstrated superb performance in high-temperature geothermal environments. The packers used in the Baca stimulation treatments and in the DST tests performed without any problems and the Y267 EPDM seals showed no signs of degradation after removal from the wells.

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